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Final Report

Field Demonstration of a Membrane Process to Recover Heavy Hydrocarbons and to Remove Water from Natural Gas

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Abstract

The objective of this project was to design, construct and field demonstrate a membrane system to recover natural gas liquids (NGL) and remove water from raw natural gas. An extended field test to demonstrate system performance under real-world high-pressure conditions was conducted to convince industry users of the efficiency and reliability of the process. The system was designed and fabricated by Membrane Technology and Research, Inc. (MTR) and installed and operated at BP Amoco's Pascagoula, MS plant. The Gas Research Institute partially supported the field demonstration and BP-Amoco helped install the unit and provide onsite operators and utilities. The gas processed by the membrane system meets pipeline specifications for dew point and BTU value and can be delivered without further treatment to the pipeline.

During the course of this project, MTR has sold thirteen commercial units related to the field test technology. Revenue generated from new business is already more than four times the research dollars invested in this process by DOE. The process is ready for broader commercialization and the expectation is to pursue the commercialization plans developed during this project, including collaboration with other companies already servicing the natural gas processing industry.

TABLE OF CONTENTS

1. INTRODUCTION	6
2. EXECUTIVE SUMMARY	6
3. EXPERIMENTAL METHODS AND APPROACH.....	7
Prepare Membranes and Modules.....	7
Design and Construct Field Demonstration System	8
Install System at Site/ Initial Evaluation	9
Develop Field Test Plan.....	11
Operate System Continuously	12
4. DEVELOPMENT OF COMMERCIALIZATION PLANS	16
Survey of Industry Users and Market Definition.....	16
Collaborative Agreement with ABB Lummus – Randall Gas Technologies for Market and Product Development.....	17
Formulating a Comprehensive Commercialization Plan	18
Developing an MTR Website Presence	19
Other/Standard Marketing Approaches: Papers, Presentations, Industry Shows, and Field Site Tours	19
5. RESULTS AND DISCUSSION	19
Case Studies from Commercial Applications	21
6. CONCLUSIONS.....	30
7. REFERENCES	30
8. ACKNOWLEDGEMENTS	31

CONFIDENTIAL APPENDIX (Submitted separately):
COMMERCIALIZATION PLAN AND DISCUSSION

1. INTRODUCTION

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During the course of this project, MTR has sold thirteen commercial units related to the field test technology. Revenue generated from new business is already more than four times the research dollars invested in this process by DOE. The process is ready for broader commercialization and the expectation is to pursue the commercialization plans developed during this project, including continued utilization of our website and collaboration with other companies already servicing the natural gas processing industry.

2. EXECUTIVE SUMMARY

The objective of this project was to design, construct and field demonstrate a membrane system to recover natural gas liquids (NGL) and remove water from raw natural gas. An extended field test to demonstrate system performance under real-world high-pressure conditions was conducted to convince industry users of the efficiency and reliability of the process. A commercialization plan was developed and executed in parallel with the field test activities and that plan has led to commercial sales valued at \$2.9 million to date.

Design of the membrane skid and manufacture of the membranes required for this project were completed in the first few months of the project, and detailed drawings were available within the first year. The years from 2000-2004 were primarily spent resolving construction issues, including a long delay involving specification of the compressor required for operation of the membrane skid. Membranes and membrane modules were prepared in 2002, and following resolution of the construction and site operation issues, installation of the membrane system finally began late in the third quarter of 2004. The system startup and initial testing began in February 2005. Plant upgrades by BP Amoco at Pascagoula, membrane replacement by MTR, and some minor delays due to the Gulf Coast hurricane season delayed the start of continuous operation of the unit. After December 2005, the unit operated continuously and smoothly, with essentially no change in performance levels through September 2006. The expectation is to run the unit for a few additional months in 2007. A photo of the MTR membrane unit at Pascagoula is provided in Figure 1.



Figure 1. MTR's field demonstration membrane-based gas treating unit at BP Amoco's gas processing plant in Pascagoula, MS. The unit operated virtually continuously from December 2005-September 2006.

Summarizing the commercialization efforts during this project, significant progress was made toward introducing MTR's NGL membrane and systems into the natural gas market. MTR sales of hydrocarbon-selective membrane systems in natural gas fuel gas conditioning units (FGCUs) now number thirteen, and orders are open for several additional units worldwide. Revenue generated from new business is already more than four times the research dollars invested in this process by DOE.

3. EXPERIMENTAL METHODS AND APPROACH

Prepare Membranes and Modules

The membrane sheets required for this project were first manufactured in 2000, using a silicone rubber/polyetherimide(PEI) composite membrane structure. A modification in the PEI support was developed to reduce an initial problem with sheet curling, which caused difficulties in the module manufacturing process. The final membrane design is shown in Figure 2. A set of eight spiral-wound modules was fabricated in 2002 (see Figure 3 for a schematic diagram of the module structure) and each module contained about sixteen square meters of membrane. QA/QC tests were performed with satisfactory results. The modules were installed into the system in 2003; however, due to a delayed system start-up until February 2005, the decision was made to replace the original modules. The replacement modules were made and operated successfully in the September 2005 restart.

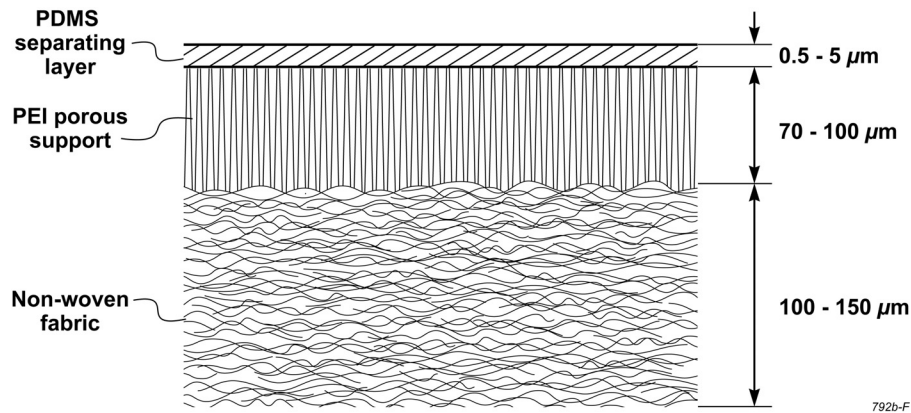


Figure 2. Design of membrane used for field demonstration unit operated at Pascagoula, MS.

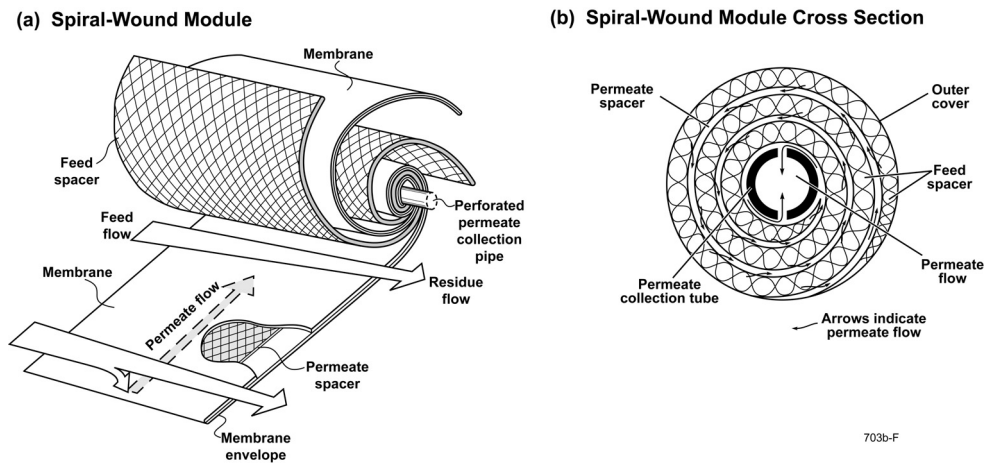


Figure 3. Exploded view and cross-section drawings of a spiral-wound module. The feed stream passes across the membrane surface. A portion passes through the membrane and enters the membrane envelope where it spirals inward to the central perforated collection pipe. One stream enters the module (the feed) and two streams leave (the residue and the permeate).

Design and Construct Field Demonstration System

The field demonstration system used in this project was based on an existing membrane skid developed by MTR for other types of natural gas separations. MTR's own engineering systems group prepared new piping and instrumentation diagrams (P&IDs) incorporating numerous modifications, and a local fabrication shop completed the required changes required to adapt the system to the Pascagoula test in 2002. The unit was shipped to the field test site in Pascagoula, MS, in early 2003.

The original membrane skid was designed as a single-stage system. In this design, the feed gas entered the membrane skid and first passed through a filter separator in which the condensate (if any) in the feed gas was removed. The gas from the separator would then enter two parallel

pressure vessels each containing up to four membrane cartridges. The permeate gases were routed out of the skid after measuring the flow rate, and the non-permeate gas was also routed out of the system through a pressure control valve.

The modified (and final) system incorporated a permeate-side compressor and a second membrane stage. A block flow diagram of the system “as-built” is shown in Figure 4. In this design, the permeated gases from the first membrane stage enter the permeate compressor for recompression from about 100 psia to the feed pressure. The compressed gas is then air-cooled and enters a gas-gas heat exchanger in which it is further cooled against the cold residue gas stream exiting the second membrane step. The gas stream from the second membrane step is then recirculated to the inlet feed.

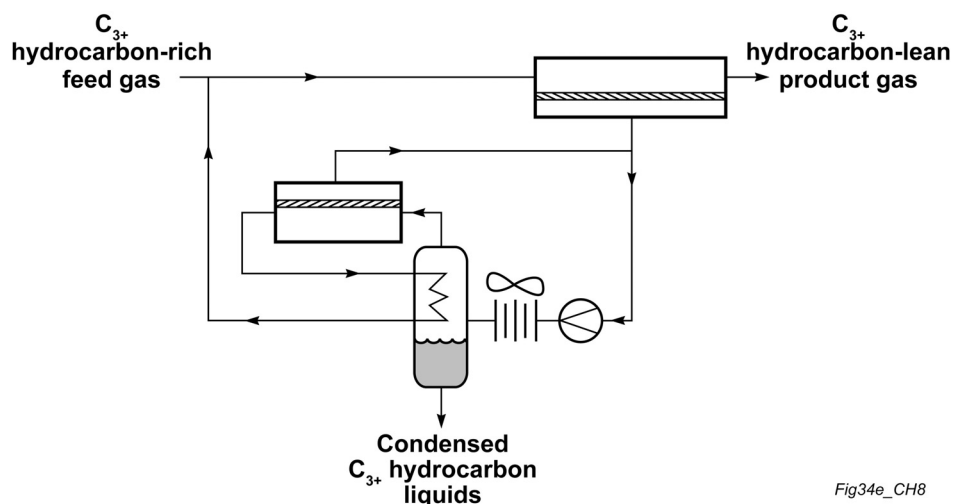


Fig34e_CH8

Figure 4. Flow diagram of the system built for operation at Pascagoula, MS.

The specification of the compressor and selection of the compressor supplier were significant factors contributing to time delays during this project. In addition to MTR’s own performance requirements, BP-Amoco imposed a series of more rigorous specifications, and provided a list of preferred, qualified suppliers different than those selected by MTR. The subsequent process of establishing exact specifications and working with different compressor fabricators was eventually resolved, although costs for the final compressor increased from initially quoted prices of around \$160-190,000 to a final custom fabrication cost of nearly \$300,000. We estimate this process alone added approximately two years to the project completion schedule.

Install System at Site/Initial Evaluation

The membrane skid and compressor units were both ready for installation by early 2003, but a major expansion in the main natural gas processing plant at Pascagoula delayed installation until late in the third quarter of 2004. During this time, on-site modifications required to accept the units were made (such as preparing the concrete base pad), and the units were transported to the planned site location. The system was hooked into the plant lines and all required electrical cable runs, motor start-ups, PLC, and related activities were completed by the end of 2004. The initial evaluation began in February 2005.

Figure 1 in the Executive Summary provides a “head-on” view of both the membrane unit and compressor in place at Pascagoula. Figures 5-7 that follow provide additional views of the installed system.



Figure 5. Membrane pilot skid and compressor skid at BP Amoco Pascagoula, MS, natural gas processing plant site.



Figure 6. Membrane pilot unit – side view prior to final installation.



Figure 7. Rear view of membrane pilot unit in Pascagoula, MS.

Develop Field Test Plan

An initial field test plan was developed in 2003, and was then fine-tuned in collaboration with the BP-Amoco participants. The final field test protocols are summarized in Table 1.

Table 1. Final Field Test Protocols for Demonstration Test at BP Amoco's Pascagoula, MS, Gas Processing Plant.

Month	Testing Protocol	MTR/BP Amoco Personnel Involvement
1	Startup/solving teething issues in the unit. Initial testing at available plant conditions	MTR onsite for 1 week of daily data collection and analysis of all key streams
2	Parametric testing of variation in pressure and flow rate	MTR onsite for 1 week to test Pressure variation: 500 – 1000 psia Flow rate variation: 1-3 MMSCFD
3	Continuous operation at available plant conditions	BP Amoco
4	Continuous operation at available plant conditions	MTR onsite for 1 week of daily data collection and analysis of all key streams
5	Continuous operation at available plant conditions	BP Amoco
6	Parametric testing of variation in pressure and flow rate	MTR onsite for 1 week to test Pressure variation: 500 – 1000 psia Flow rate variation: 1-3 MMSCFD

Operate System Continuously

The system was commissioned in February 2005, but was performing below expectations within a few days. A decision was made to replace the membrane modules, so new modules were prepared while plant upgrades were being performed at Pascagoula. A restart in September 2005 was successful in its first week, and after a brief shut down for some small changes in filters and level controllers, the system was restarted again for longer-term, continuous high-pressure testing. Two 8-inch modules were installed in series in stage one, and one 8-inch module was installed in stage two. The unit operated essentially continuously from December 2005-September 2006 with constant conditioning performance.

Initial Data Collection and Calibration

One of the first protocol tests we performed was a comparison/calibration of the inlet gas composition as measured by the BP plant on-line GC and MTR's portable field GC. Results from three consecutive days in October 2005 are presented in Table 2.

Table 2. Comparison of Inlet Gas Composition Measurements from the BP Plant On-Line GC and the MTR Portable Field GC During Early Restart (October 19-21, 2005).

Gas Component	Gas Compositions (vol%)					
	Day 1		Day 2		Day 3	
	BP	MTR	BP	MTR	BP	MTR
N ₂	0.29	0.92	0.3	0.92	0.31	0.77
CO ₂	0.29	0.28	0.26	0.28	0.26	0.28
CH ₄	93.48	93.61	94.05	93.61	93.93	93.24
C ₂ H ₆	2.80	2.39	2.57	2.39	2.59	2.50
C ₃ H ₈	1.67	1.57	1.52	1.57	1.57	1.76
i-Butane	0.29	0.23	0.26	0.23	0.26	0.25
n-Butane	0.57	0.47	0.51	0.47	0.53	0.53
i-Pentane	0.17	0.17	0.15	0.17	0.15	0.18
n-Pentane	0.16	0.18	0.15	0.18	0.15	0.21
Hexane+	0.27	0.16	0.24	0.16	0.24	0.29

The results obtained using the MTR GC were consistent with the plant measurements, except for the N₂ and hexane⁺ readings. N₂ content measured using the MTR GC was always higher than that measured by the on-line system, the discrepancy between the measurements can be attributed to the sampling method. For example, there could be residual air in the sampling bag or in the tubing connecting the GC column. The hexane⁺ differential improved by the third day, but was expected to be difficult to match due to the complex nature of the mixture.

Confirmation of measurements was necessary between the field test data for the feed, residue and permeate composition of each membrane unit and the compositions generated by the membrane simulation module used for ChemCad design calculations of each membrane unit. For each stream,

pressures and temperatures were measured by in-situ indicators, and gas composition was measured using an on-site gas chromatograph. Flow rates of the feed and permeate streams in stage one were measured using flow meters, and the flow rates of other streams were calculated based on these two flow rates and stream compositions. Tables 3 and 4 show the comparison of the field test data and simulation results at a feed pressure of 788 psia.

Table 3. Comparison of ChemCad Simulation Results and Field Test Results for Stage One Membrane Unit at Pascagoula.

Stage One Membrane Unit ^a	Feed ①		Residue ②		Permeate ③	
	Chem Cad	Field Test	Chem Cad	Field Test	Chem Cad	Field Test
Operating Conditions						
T [°F]	68	70	55	53	62	--
P [psig]	788	788	763	710	90	90
Flow Rate [MMscfd]	2.5	2.5	2.0	--	0.52	0.5
Stream Compositions (vol %)						
N ₂	0.92	0.49	0.78	0.47	1.43	0.80
CO ₂	0.32	0.34	0.28	0.28	0.46	0.48
CH ₄	92.5	93.2	94.3	94.3	85.7	85.9
C ₂ H ₆	2.81	2.60	2.41	2.43	4.33	4.13
C ₃ H ₈	2.0	1.93	1.48	1.46	4.12	3.91
i-C ₄ H ₁₀	0.27	0.28	0.18	0.21	0.62	0.67
n-C ₄ H ₁₀	0.56	0.57	0.34	0.41	1.4	1.51
i-C ₅ H ₁₂	0.18	0.19	0.08	0.13	0.55	0.70
n-C ₅ H ₁₂	0.20	0.19	0.08	0.14	0.63	0.76
Hexane+	0.24	0.18	0.10	0.13	0.78	1.18

a. Streams for which data are reported are indicated on the following flow diagram of the system at Pascagoula.

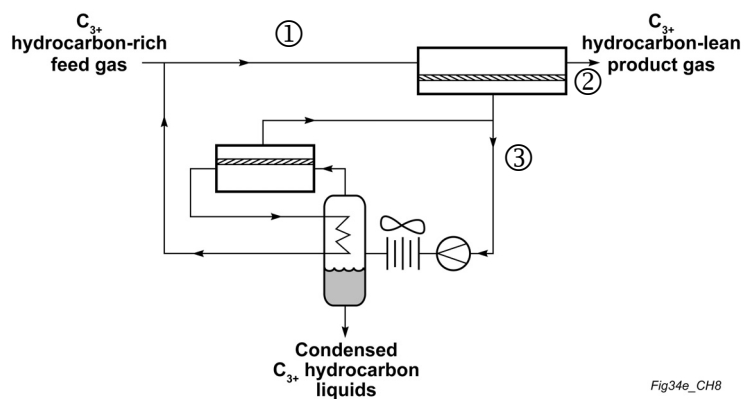
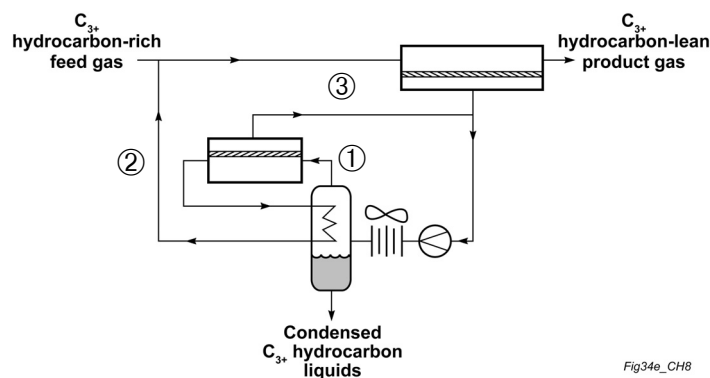


Table 4. Comparison of ChemCad Simulation Results and Field Test Results for Stage Two Membrane Unit at Pascagoula.

Stage Two Membrane Unit ^a	Feed ①		Residue ②		Permeate ③	
	Chem Cad	Field Test	Chem Cad	Field Test	Chem Cad	Field Test
Operating Conditions						
T [°F]	62	62	25	--	44	--
P [psig]	830	--	810	--	70	--
Flow Rate [MMscfd]	0.83	--	0.49	--	0.34	--
Stream Compositions (vol %)						
N ₂	1.25	0.42	1.52	0.35	0.87	0.25
CO ₂	0.59	0.60	0.46	0.48	0.77	0.77
CH ₄	83.5	84.1	89.3	90.6	75.0	76.7
C ₂ H ₆	6.18	6.59	4.1	3.96	9.21	9.07
C ₃ H ₈	5.5	5.15	3.15	3.00	8.91	8.00
i-C ₄ H ₁₀	0.69	0.73	0.36	0.40	1.17	1.18
n-C ₄ H ₁₀	1.36	1.43	0.69	0.75	2.34	2.34
i-C ₅ H ₁₂	0.35	0.37	0.17	0.19	0.62	0.62
n-C ₅ H ₁₂	0.35	0.37	0.15	0.16	0.64	0.62
Hexane+	0.21	0.24	0.06	0.09	0.43	0.48

- a. Streams for which data are reported are indicated on the following flow diagram of the system at Pascagoula.



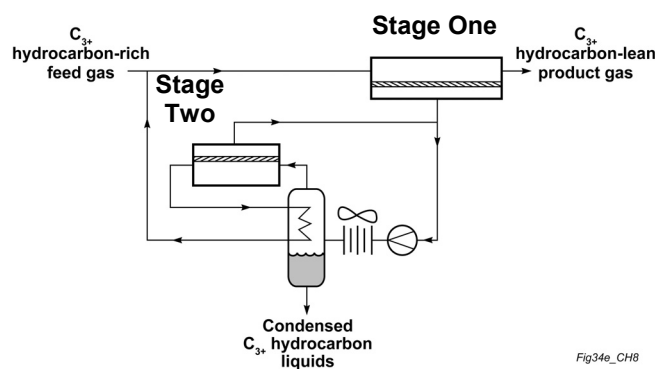
Membrane Module Performance

Gas permeance and selectivity of the stage one and stage two membrane modules during field tests at various pressures, feed flow rates and stage cuts are summarized in Table 5. The data were taken after the tests reached steady state. Permeances were calculated based on the measured flow rates, pressures, temperatures, and compositions of each stream. Permeance values were also positively confirmed using ChemCad.

Table 5. Gas Permeance and Selectivity of the Stage One and Stage Two Membrane Modules During Field Tests at Pascagoula Under Various Operating Conditions (October 2005).

Operating Conditions	Test One		Test Two		Test Three		Test Four	
T [°F]	70		70		80		80	
P [psig]	690		788		911		914	
Flow Rate [MMscfd]	2.6		2.9		2.9		2.3	
Stage Cut (%)	16		18		25		28	
Stage One Membrane Module Results								
Gas Component	Permeance (gpu)	Selectivity (Gas/CH ₄)	Permeance (gpu)	Selectivity (Gas/CH ₄)	Permeance (gpu)	Selectivity (Gas/CH ₄)	Permeance (gpu)	Selectivity (Gas/CH ₄)
CO ₂	208	2.0	244	1.9	383	3.0	314	2.9
CH ₄	106	1.0	130	1.0	130	1.0	108	1.0
C ₂ H ₆	229	2.2	264	2.0	278	2.1	229	2.1
C ₃ H ₈	359	3.4	424	3.3	355	2.7	292	2.7
i-C ₄ H ₁₀	448	4.2	553	4.3	420	3.2	345	3.2
n-C ₄ H ₁₀	530	5.0	670	5.1	462	3.6	378	3.5
i-C ₅ H ₁₂	898	8.4	1,361	10	539	4.2	439	4.1
n-C ₅ H ₁₂	1,115	10	1,551	12	594	4.6	480	4.4
Hexane+	-	-	-	-	1,417	11	1,094	10
Stage Two Membrane Module Results								
Gas Component	Permeance (gpu)	Selectivity (Gas/CH ₄)	Permeance (gpu)	Selectivity (Gas/CH ₄)	Permeance (gpu)	Selectivity (Gas/CH ₄)	Permeance (gpu)	Selectivity (Gas/CH ₄)
CO ₂	289	1.8	259	1.8	-	-	-	-
CH ₄	158	1.0	145	1.0	-	-	-	-
C ₂ H ₆	375	2.4	332	2.3	-	-	-	-
C ₃ H ₈	461	2.9	396	2.7	-	-	-	-
i-C ₄ H ₁₀	508	3.2	439	3.0	-	-	-	-
n-C ₄ H ₁₀	525	3.3	456	3.2	-	-	-	-
i-C ₅ H ₁₂	549	3.5	485	3.4	-	-	-	-
n-C ₅ H ₁₂	587	3.7	530	3.7	-	-	-	-
Hexane+	814	5.1	749	5.2	-	-	-	-

Units for which data are reported are indicated on the following flow diagram of the system at Pascagoula.



In stage one, mixed-gas methane permeance for each test was around 110-130 gpu, which is higher than the pure-gas methane permeance (80 gpu). However, this is expected since the presence of higher hydrocarbons such as butane can significantly plasticize the membrane, leading to an increase in methane permeance. Methane permeance in stage two was even higher (145-158 gpu), probably because of higher concentration of higher hydrocarbons in the feed, leading to stronger plasticization. Nevertheless, hydrocarbon/methane selectivities are more or less consistent from test to test. For example, ethane/methane selectivity is about 2.0-2.5 for all the tests. These results are consistent with test results in our laboratory for the same membrane compositions. The field test

membrane modules performed well and stably in the observed range of pressures and stage-cuts. In broader terms, the field tests demonstrated the robustness of the membrane modules in rich natural gas environments (high pressure and high C₃₊ content), combined with membrane hydrocarbon/methane selectivity values appropriate for fuel gas conditioning use.

4. DEVELOPMENT OF COMMERCIALIZATION PLANS

Survey of Industry Users and Market Definition

Commercialization for this project was initiated by conducting a survey of industry participants with potential interest in the separation technology being developed. Approximately ten companies were surveyed in year one, and an additional thirty companies the following year. Applications identified included fuel gas conditioning and wellhead gas processing as target areas for the technology. Initial market analysis estimated the market size for membrane systems in these markets at just over \$100 million annually. Based on experience to date, this figure has been adjusted downwards to \$60 million per year. The nature of the opportunity has also changed.

Experience indicates that the most accessible portion of the market is fuel gas conditioning for field engines and turbines. These potential users fall into two groups:

- Engine and gas turbine operators whose gas is too heavy for efficient operation. Operators normally handle this problem by running the engine or turbines below the maximum rating. If the de-rated engine still provides sufficient power for the operation, the fuel quality problem is solved. However, if the operator requires the full potential output of the engine or turbine, his alternatives are to buy a second engine or install some form of fuel conditioning system. For a membrane unit to be competitive, it must be significantly cheaper than the second engine option. For most situations, this puts the unit price of these systems at \$150,000 to \$200,000. These prices can be achieved by using standard system designs.
- Gas turbine operators with gas containing from 0.1 to 1.0% hydrogen sulfide (H₂S). These levels of hydrogen sulfide are too high to be removed by chemical reactants, and the gas flow is far too small to make an amine plant practical. The only current option for these operators is to bring in sweet gas or use diesel or electric-powered engines. This group of operators is smaller than the group of engine and gas turbine operators, but is much more motivated to install membrane equipment. They are also less price-sensitive to the ultimate cost of the systems. A large fuel gas system treating gas containing 3,400 ppm H₂S was installed at a gas field in British Columbia, Canada, during this project and has been operating without problem.

Wellhead gas processing and NGL recovery from rich gas is the other major application area for the technology developed. This is a very large application, and approximately 1,000 new wells that could potentially use membrane technology come on stream every year. Many of these wells will not install any type of NGL treatment technology. If NGL treatment is required, then propane refrigeration systems are the most economic approach to treatment. However, there are situations where refrigeration is not practical, for example on offshore platforms treating associated gas. The

high maintenance, bulk, and power requirements make use of propane refrigeration systems uneconomic. As a result, the associated gas is often reinjected into the formation. Some offshore operators have expressed interest in the membrane technology, and the economics of the membrane system appear to be reasonable. As the technology becomes established in smaller fuel conditioning applications, it will be possible to capture a portion of this market.

Current estimates for the portions of the gas treating market this technology could capture are given in Table 6 below. The total potential market is about \$60 million per year. In 2006-2007, MTR is expected to sell about \$1 million of systems, so only a small fraction of the total market has been captured and prospects for future growth are good.

Table 6. Projections of the Annual Market for Membrane-based Fuel Gas Conditioning Units.

Application	Currently Installed Units	Projected Annual New Installations	% Suitable for Membrane Systems	Approximate Price per System (\$US 000)	Potential Annual Market Size for New Installation Systems (\$US millions)
Wellhead Natural Gas Conditioning					
Onshore	12,000	1,000	2	500	10
Offshore	4,000	300	10	1,000	30
Fuel Gas Conditioning – Gas Turbines	4,000	300	10	400	12
Fuel Gas Conditioning – Gas Engines	4,000	400	10	200	8
Total					\$60 million

Collaborative Agreement with ABB Lummus – Randall Gas Technologies for Marketing and Product Development

Simultaneously with the survey efforts, the project team consulted with Mr. Carter Tannehill of Purvin and Gertz, Inc., a consultant to the gas processing industry, headquartered in Dallas, Texas. He provided a detailed report on strengths and weaknesses of existing gas processing technologies and industry costs. The report also included suggestions for potential marketing partners in the gas processing area.

During 2001 and 2002, MTR explored the possibility of collaborating with a large multinational company as a marketing and sales partner, and in September 2002, MTR signed a marketing agreement with ABB Lummus Global and its Randall Gas Technology Group, located in Houston, Texas. Randall is a world leader in supplying technology and equipment for large natural gas processing projects. In addition to providing access to Randall's marketing channels and the expertise of their process and engineering staff, partnering with Randall provided customer

credibility with the gas processing industry for the technology. The relationship continues to the present time.

As part of the alliance activities, MTR and ABB Lummus Global have developed various strategies and tactics to address key requirements of the customers. Specific actions taken by MTR included

- Developing a standardized layout and membrane skid to lower repetitive engineering costs and to develop essentially reusable systems.
- Developing a detailed package of system specifications to allow rapid transfer of information to potential clients.
- Building a network of fabrication shops and contacts to minimize building costs and accelerate delivery schedules.

Completing all of these tasks has allowed the MTR-ABB alliance to respond quickly and efficiently to inquiries from potential customers, as well as to offer units that are well-priced in terms of payback time for the user.

Formulating a Comprehensive Commercialization Plan

Most of the seven-point plan developed to commercialize this technology was formulated in conjunction with ABB Lummus Global in 2004, and refined in later years. A total of thirteen FGCU units have been built and installed for use in remote gas processing locations, and inquiries and orders from companies worldwide continue to be received.

The seven points addressed in the commercialization plan included:

1. Access to markets and collection of qualified leads and prospects
2. Ability to provide a technically adequate solution
3. Customer confidence and comfort with the new technology
4. Development of a competitive and profitable pricing structure
5. Timely delivery of orders
6. Ability to predict and control costs to ensure profitability
7. Ability to provide client with alternative financing methods, including leases and processing fees.

A separate Confidential Business Information document summarizes the major challenges in the commercialization plan, including pertinent examples from commercialization efforts during the course of the project.

Developing an MTR Website Presence

Separately from the collaborative agreement with ABB Lummus – Randall, MTR began marketing the new FGCU technology using the MTR website at www.mtrinc.com. Immediate increases in website traffic occurred following the introduction of the natural gas products in 2001. The website approach has produced consistent results in generating high quality leads and inquiries for sales of fuel gas conditioning units. All systems sales related to this project started from website marketing leads. Website inquiries are received every week, in addition to leads from other established marketing channels. A revised and expanded section of the MTR website, devoted to natural gas applications, will be rolled out this summer (2007).

Other/Standard Marketing Approaches: Papers, Presentations, Industry Shows, and Field Site Tours

Summaries of the FGCU progress were presented at the Gas Processors' Association (GPA) in 2000, 2004, and 2006, and, in conjunction with ABB/Lummus partners, at the Laurance Reid Gas Conditioning Conference in 2004 and 2006. MTR presented at the European GPA in Barcelona, Spain, in September 2000. The MTR paper received one of the three best-overall-presentation awards at the 2000 GPA meeting. Also, MTR participated in the biannual International Expo in Calgary, Alberta, for the first time, in June 2006. The booth and handout materials included several FGCU case studies.

The continuous operation of the demonstration unit at BP Amoco provided excellent opportunities to showcase the unit with project participants and prospective clients. Several guests from GRI/GTI and operating companies were given a site visit following the Spring 2006 GPA meeting. During the visit, an operator from the site offered the unsolicited comment that the unit had been operating very smoothly since the December 2005 start-up further reassuring the performance of the unit.

5. RESULTS AND DISCUSSION

During the past three years, over 100 design and price quotations and evaluations have been submitted to different companies, providing MTR with significant insights into both the technical and marketing areas of FGCU technology. This work has resulted in the sales of thirteen commercial units valued at \$2.9 million. These sales, brief descriptions of the systems, and pertinent technical and operating experience gained in relation to the project technology are summarized in Table 7.

Table 7. Commercial Sales and Experience Gained As a Result of Work on this Project.

Customer	Date Sold/ Started Up	Unit Description	Experience Gained/ Customer Status
Customer A Pakistan	2007	One FGCU for genset operation.	Ready for delivery.
Customer B Texas, USA (2)	2006-2007	Two FGCU's to reduce C ₂₊ components and lower emissions from a large central compressor.	Systems are operational.
Customer C Texas, USA	June 2006	Four-module FGCU for a field compressor engine.	System has been operational since October 2006. Methane number of fuel raised from 40 to 70. Customer happy.
Customer D New Mexico, USA (2)	2005	Two FGCU's for remote operation of Superior and Waukesha engines at compression stations.	Both units have been operating unmanned, providing better-than-guarantee quality even though the raw gas being conditioned was richer than the design values.
Customer E Kakap Field Indonesia	Early 2005	Offshore platform FGCU to prevent compressor derating.	System has been operational since early 2005. Methane number of fuel raised from 16 to 71; compressor engine knocking disappeared completely. Customer happy.
Customer F Bakersfield, CA, USA	Early 2005	One FGCU skid to reduce total emissions and improve engine performance.	Unit has been in continuous operation since installation. Expansion is planned at the site.
Customer G British Columbia, Canada	2003-04	16-module FGCU with H ₂ S and NGL removal capability for remote site operation.	Customer was able to switch from trucked-in diesel to use of onsite natural gas slipstream for compressor engine fuel. Unit operated for four years with no replacements.
Customer H Glitne Field North Sea	2003-04	FGCU to improve fuel feed to a three-engine genset on an FPSO ship.	Membrane unit significantly improved performance of the Wartsila engines on the FPSO. Unit was designed and installed with vertical module tubes, a first for MTR, to minimize unit footprint.
Customer I Curitiba, Brazil	Dec 2001- May 2002	FGCU for two Siemens 250 MW power plant turbines.	Provided on quick turnaround (86 days), to avoid construction/operation penalties; producer of traditional cryogenic gas treatment unit could not deliver quickly enough. Early performance met specs; now operated as back-up unit.
Customer J Gulf of Mexico USA	2001 (2Q)	Small FGCU for an offshore platform.	Status unknown.
Customer K Norway	2001	High-pressure test system for NGL removal from natural gas.	Unit operated for a few months. Flow changes in pipeline restricted further use.

Case Studies from Commercial Applications

Several of the customers for whom we have built FGCU or other heavy hydrocarbon treatment systems have agreed to release selected aggregate data results. The following case studies provide descriptions of the operating conditions and treatment results at five different installations for removal of heavy hydrocarbons from natural gas. Photographs of each unit are also provided.

Remote Gas Platform Off Indonesia

A pre-owned compressor was purchased and installed on the Kakap-H platform operated by Star Energy off Indonesia. This production area is one of the most remote in the world.

The engine driving the compressor was expected to run smoothly using the available wellhead gas on the platform. However, the methane number of the gas (a natural gas equivalent of octane number for ratings) was only sixteen. With raw gas, the compressor would have to be de-rated, severely, by up to forty percent. The customer could not operate the compressor for more than a few hours at a time and the engine would shut down due to knocking.

The customer installed a membrane FGCU to process the gas (Figure 8). A compact unit was placed on a mezzanine above the compressor to save space. With the membrane system online, the compressor problems disappeared completely. The engine stabilized and ran continuously without shutdowns or knocking. The membrane FGCU was producing a premium quality fuel with a methane number of seventy-one. Comparisons of the feed gas and conditioned fuel gas compositions are provided in Table 4. The unit began operation in early 2005.



Figure 8. Membrane-based FGCU installed on Kakap-H remote natural gas platform, Indonesia.

Table 8. Gas Compositions of Kakap-H FGCU Before and After Gas Conditioning. Data provided by Mr. Zikri Syah, Star Energy.

Gas Stream Component	Gas Compositions	
	Feed Gas (mol %)	Conditioned Fuel Gas (mol %)
Propane	4.60	1.48
i-Butane	1.97	0.52
n-Butane	1.53	0.30
Pentanes	1.74	0.28
Hexane	1.05	0.126
C ₆₊	0.91	0.078
Balance Methane and Ethane		
Total C ₃₊ Hydrocarbons	11.76	2.78
Methane Number	16	71

Sour Gas Processing in British Columbia

The request for this skid came from Dominion Exploration, who operates gas recovery operations in remote areas of British Columbia. Hydrogen sulfide (H₂S) content of the natural gas product was forcing the company to use diesel as fuel for the engine driving the production compressors. The customer wanted a solution that would reduce H₂S in the product gas to the level that onsite gas, instead of trucked-in diesel, could be used to fuel the compressor engine.

Before committing to a membrane separation unit, the company considered established chemical scrubbing technologies including amines (which required a building around the amine unit to keep it from freezing) or scavengers (which required chemicals with high operating costs). A membrane unit provided the most favorable combination of capital and operating costs.

The membrane process both lowered the H₂S content to 40 ppm (guaranteed 300 ppm) and reduced the heavy hydrocarbons in the gas, creating a useful engine fuel slipstream (Table 9).

The system (Figure 9) was started up in 2003.

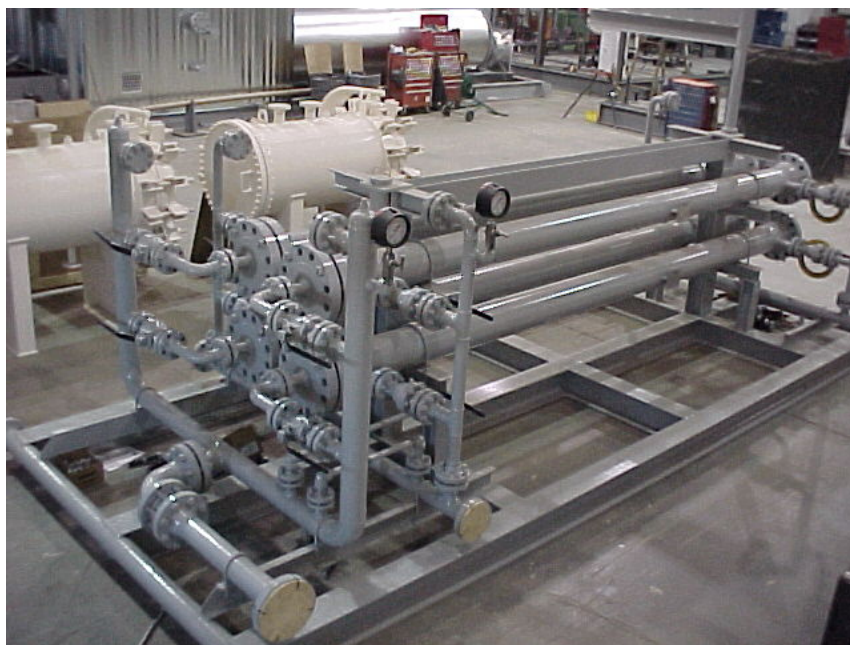


Figure 9. Sour gas/FGCU unit installed at a remote gas recovery site in British Columbia, Canada.

Table 9. Gas Compositions from a Membrane-Based Sour Gas/FGCU Before and After Gas Conditioning. Data provided by Mr. Brett Kimpton, Dominion Exploration.

Gas Stream Component	Feed Gas (mol%)	Conditioned Gas (mol%)
Hydrogen sulfide	0.34	0.004
Propane	2.72	0.624
i-Butane	0.37	0.049
<i>n</i> -Butane	0.67	0.088
i-Pentane	0.18	0.018
<i>n</i> -Pentane	0.19	0.019
Hexane	0.16	0.010
C ₆ +	0.14	0.008
Total C ₃ + Hydrocarbons	4.43	0.82
H ₂ S Content	3,400 ppm	40 ppm

Three-Engine Genset on North Sea Platform

For this application, an FGCU was successfully installed on an FPSO (Floating Production, Storage and Offloading) ship in the North Sea, at the Glitne Field operated by Statoil. The unit came online in 2004, and provides another example of successful membrane deployment in a remote offshore location.

This FPSO uses three gas engines in a Genset for power generation. The original engine fuel gas came directly from the associated gases produced during oil production, and was of low fuel quality. After initial installation of the Genset, the FPSO operators discovered that the associated gas fuel was so poor that the gas engines ran derated, resulting in a lower-than-required electrical output. The membrane process was found to be an ideal fit for upgrading this low-pressure fuel gas, in an environment with strict requirements on space utilization. MTR built this unit in a vertical orientation, further minimizing the FGCU footprint. A photo (Figure 10) and table of gas specifications obtained on the FPSO (Table 10) follow.



Figure 10. Membrane-based FGCU prior to installation on a North Sea FPSO ship. The unit was installed with the module tubes in a vertical position (perpendicular to the ship deck), in order to minimize the footprint of the unit.

Table 10. Gas Compositions for a North Sea FPSO Ship FGCU Before and After Gas Conditioning.

Gas Stream Component	Inlet Feed (mol %)	Conditioned Fuel Gas (mol %)
Methane	72.94	86.95
Ethane	9.73	5.68
Propane	8.51	3.18
Butanes	5.05	1.10
Pentanes	1.63	0.30
Carbon dioxide	0.40	0.25
Nitrogen	1.22	2.49
n-Hexane	0.52	0.06
Methane number	32	65
Pressure (bar)	13.8	10.3
Volume (MMscfd)	5.5	1.8

Gas Conditioning for 500 MW Power Plant Turbines in Brazil

In this application, membrane separation is used for conditioning fuel gas fed to a set of two Siemens 250 MW power plant turbines. This power plant project was built for El Paso Gas/ UEG Araucaria in Curitiba, Brazil, to deliver 500 MW of power.

To meet operating guarantees, Siemens turbine specifications restricted the C₃ and C₄₊ content of the fuel gas. The Bolivian gas delivered to this plant was going to be an off-spec gas at the anticipated startup date. The Brazilian client required a solution that would allow him to bring the turbines online quickly, while avoiding delays in meeting an aggressive penalty-based schedule. Because of the large plant size, conventional cryogenic processes for gas conditioning were planned for use at the site. However, the supplier could not provide gas conditioning units by the required delivery dates, and therefore a membrane-based unit was also installed.

The membrane plant was built to process about 120 MMscfd with both turbines operating, and was delivered in 86 days. The membrane skids were built as two identical air-transportable units, and they were transported to the site via air. The units were put in place as two parallel trains, each handling half the gas flow rate (Figure 11).

Start-up of the membrane unit went smoothly and performance of the unit was better than guaranteed (Table 11). This unit represents the largest gas flow rate treated by membranes of the type developed for commercial use in this project.



Figure 11. FGCU skids built to remove heavy hydrocarbons from onsite gas used as fuel for two 250 MW Siemens power plant turbines in Curitiba, Brazil. The unit was built on two identical compact skids so that the equipment could be shipped easily by air.

Table 11. Gas Compositions at an FGCU Before and After Gas Conditioning for a 500 MW Power Plant Using Siemens Turbines in Brazil.

Gas Stream Component	Gas Compositions	
	Feed Gas (mol %)	Conditioned Fuel Gas (mol %)
Propane	2.000	1.489
C ₄₊	0.785	0.449
Pressure (psig)	700-900	
Flow rate (MMscfd)	120 MMscfd	

Fuel Gas Conditioning for Superior and Waukesha Engines in New Mexico

Two FGCU units were deployed in 2005 at compression stations owned by The Sid Richardson Company in New Mexico. The available field gas was of poor quality and derated performance of the compressor engines was expected. The customer made the decision to incorporate membrane-based FGCU's at the same time the new engine/compressor sets were installed at both sites.

Both compact FGCU's have been operating for several months at these unmanned sites, providing fuel gas with better-than-guarantee quality, even though the raw gas being conditioned was richer than the design values. Both compressors are working with no performance derating and with no shutdowns due to knocking or pre-detonation.



Figure 12. Membrane-based FGCU installed at one of Sid Richardson Company's compressor stations in New Mexico.

Table 12. Comparison of Guaranteed and Actual Gas Compositions for an FGCU Operating at an Unmanned Compressor Station in New Mexico. Data provided by Gary McCoy, Sid Richardson Company, Dallas, TX.

Gas Stream Component	Guaranteed Performance		Actual Performance	
	Inlet Feed (mol %)	Conditioned Fuel Gas (mol %)	Inlet Feed (mol %)	Conditioned Fuel Gas (mol %)
Methane	73.3	81.99	69.58	81.19
Ethane	10.89	6.93	11.23	6.89
Propane	6.00	2.63	6.53	2.35
Butanes	2.55	0.56	2.53	0.66
Pentanes	1.07	0.2	0.77	0.16
Carbon dioxide	1.63	0.85	4.67	3.07
Nitrogen	3.71	6.69	4.05	5.41
n-Hexane	0.83	0.126	0.37	0.07
Methane Number	39	67	44.4	68

Additional Commercial Units

The case studies in this section included photographs of FGCU units provided to several customers; two additional units are shown below.

Figure 13. The FGCU unit ordered by a major U.S. pipeline company in the third quarter 2006 (Customer B). The company ordered a second identical unit in the first quarter of 2007.

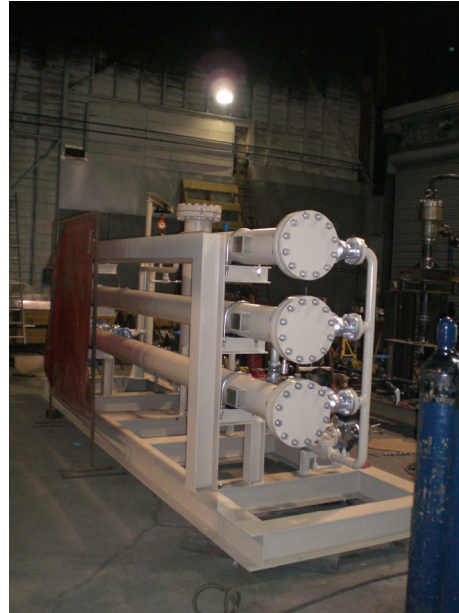


Figure 14. FGCU for an oil exploration firm, used at a California site to reduce total emissions and improve engine performance (Customer F).



6. CONCLUSIONS

This demonstration project consisted of two distinct parts. The first part involved building, installing, and testing a demonstration plant for NGL separation and recovery and the second part involved commercialization activities. The first part of the project experienced many unavoidable delays due to various equipment requirements and other priorities at the host site. The first tests started in 2005. The unit operated from December 2005-September 2006 with essentially constant conditioning/separation performance. The field tests have been extended into 2007 and BP Amoco continues to provide support of day-to-day operating expenses at the plant.

The second portion of the project, the commercialization of the technology, has progressed very well. Several commercial units using the membrane technology developed in this project have been sold and installed. These installations have been operating satisfactorily for their owners. We attribute part of this success to our efforts at firming up our processes and procedures for commercialization of the technology and implementing them. In particular, our website marketing strategy is yielding very good results in leads generation.

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